Chair for Management Sciences and Energy Economics

University of Duisburg-Essen

EWL Working Paper No. 3

MODELLING THE IMPACT OF DIFFERENT PERMIT ALLOCATION RULES ON OPTIMAL POWER PLANT PORTFOLIOS

by

Christoph Weber,

Philip Vogel

and

Oliver Woll

August 2007

Modelling the impact of different permit allocation rules on optimal power plant portfolios

by Christoph Weber, Philip Vogel and Oliver Woll

Abstract

The electricity generation mix of many European countries is strongly dominated by fossil fuelled power plants. Given that CO2-emissions are responsible for a major part of the anthropogenic greenhouse effect, emission trading has been introduced in the EU in 2005. Under the European emissions trading scheme (ETS), the emission quantities of major industry branches, most notably the electricity industry are capped and a system of tradable CO2 emission permits is established. Although the effects of emission trading on emissions, industry structure and investment had been analysed on beforehand by a number of models, the impact of rules for primary permit allocation has so far hardly been focused on. This was mostly seen as a distributional issue not affecting the efficiency of the market mechanism itself. However a closer look at the permit allocation rules shows that the number of permits allocated to new plants often depends on their fuel and technology (e. g. in Germany). This may consequently have distorting effects on market prices and investment decisions, which so far have been hardly investigated quantitatively. In order to analyse such effects, a mixed complimentary programming (MCP) model is developed, which allows to model investment incentives in the electricity sector. It takes into account major power generation technologies, emission constraints, endogenous investment allocation rules and price elasticity of demand. In particular also the time-varying structure of electricity demand is accounted for and the corresponding distinction of base- and peak-load technologies. The model is applied to the EU-27 focusing on the year 2015, i.e. on the third trading period, where so far no decision has been made on the allocation rules to be applied. From this analysis we derive the average market prices for emission allowances and electricity and the optimal power plant capacities under different allocation schemes. In a pure environmental perspective the auctioning of permits is expected to be a first-best solution, but it could endanger the competitiveness and the security of supply of the European Union.

The reason for the latter is that the generation mix becomes biased in favour of gas fuelled plants, which are associated with the least specific CO2-emissions, but have to be imported to a large extent from politically unreliable regions like Russia or the Middle East. The results of our analysis however show that allocating emissions for free, based on expected full-load hours and fuel specifics, will lead to higher CO2-prices whilst the effect of securing supply is only limited. Also electricity prices will only be slightly lower, so that the contribution of free allocation schemes to economic competitiveness is also limited.

Keywords : climate protection, security of supply, emission trading, allocation of emission permits, electricity markets, power plant portfolio

JEL-Classification : P51, Q40, Q41, Q58

PROF. DR. CHRISTOPH WEBER
Chair for Management Sciences and Energy Economics,
University of Duisburg-Essen (Campus Essen)
Universitätsstr. 11, 45117 Essen
++49 - (0)2 01 / 183-2966
www.ewl.wiwi.uni-due.de
christoph.weber@uni-due.de

DIPL.-VOLKSW. PHILIP VOGEL
Chair for Management Sciences and Energy Economics,
University of Duisburg-Essen (Campus Essen)
Universitätsstr. 11, 45117 Essen
++49 - (0)2 01 / 183-3399
www.ewl.wiwi.uni-due.de
philip.vogel@uni-due.de

DIPL.-KFM. OLIVER WOLL
Chair for Management Sciences and Energy Economics,
University of Duisburg-Essen (Campus Essen)
Universitätsstr. 11, 45117 Essen
++49 - (0)2 01 / 183-3389
www.ewl.wiwi.uni-due.de
oliver.woll@uni-due.de

1 Introduction

During the last few years it became clear that anthropogenic CO_2 emissions most probably have a severe impact onto the global climate (e.g. IPCC 2007) and onto the global economy (e.g. Nordhaus 2007). Therefore the European Union has obliged itself within the Kyoto protocol to reduce its 1990 CO_2 emissions by 8% until 2012. It decided to make use of the possibility of bubbling, which is foreseen within the Kyoto protocol and distributed the reduction target between its member states within the burden sharing agreement (EC 1999). In 2005 a joint system of tradable emission permits, which caps CO_2 – emissions of all member states, was introduced (EC 2003). From a theoretical viewpoint the system of tradable permits is a first best instrument for achieving cost minimal abatement goals (cf. Coase 1960, Tietenberg 1986), but when introducing this system into practise some issues of market design have to be addressed (e.g. Harrison and Radov 2002).

Whereas some crucial features of this emission trading scheme, like monitoring and reporting, were planned centrally by the EU, many important details regarding the ETS were left to decide by the member states on their own. The reason invoked for this procedure is the principle of subsidiarity, which states that as much autonomy as possible has to be left to the member states when introducing pan-European laws. In order to be in line with the Kyoto targets and to avoid competitive distortions between countries, an additional control of national policies was foreseen.

The member states were advised to plan their national abatement efforts through the use of so called national allocation plans (NAPs), which have two main purposes: Within a macro plan emission reductions have to be distributed among different sectors of an economy, namely households, traffic, industry and energy business. Only those industry branches with the highest amount of emissions (metallurgy, minerals and pulp) and large energy companies are part of the ETS. The other sectors within the macro plan, not taking part within the ETS, can be subject to other kinds of national environmental policies, e.g. ecological taxes or regulatory laws. Altogether, a policy mix has to be designed which ensures that the emission cap, stemming from the burden sharing agreement, will be met.

Meanwhile, in the micro plan of a NAP the allocation of emission allowances regarding the single installations covered by the ETS has to be addressed. So far the European Commission prescribed that up to 5% of all allowances in the first and 10% in the second trading period may be auctioned to these installations. The larger part of the allowances had to be distributed for free to the covered companies; this process is often generally labelled as Grandfathering, albeit especially some rules more precisely correspond to some benchmark approach (s. below). Within the NAPs for the first two trading periods the member states didn't make excessively use of the option to auction, although in theory this is the best way to allocate permits (e.g. Rogge et al. 2006). For the post Kyoto era after 2012 only first proposals for the rules to be applied for allocation exist so far (notably EU 2008). In this article some pros and cons of different allocation policies will be analysed and quantified with a special consideration of the electricity industry.

There are several reasons to focus onto the electricity industry. First of all, electricity generation is responsible for an important part of anthropogenic CO_2-emissions and therefore has a severe influence on the EU emissions (about one third of all GHG emissions, EEA 2007). Another important fact is that electricity companies are not facing international competition outside the European Union and are not suffering from comparative disadvantages when pressure from environmental regulation is increased. All other relevant industry branches compete with non regulated firms from other countries, and companies might decide to relocate outside the European Union when their costs are increased through the ETS. This process is often accompanied with increasing emissions due to less restrictive environmental regulations outside of the European Union - this is the so-called leakage effect. Another important aspect is that within some processes of related industries, e.g. steel production, there is almost no flexibility to reduce CO_2-emissions, so that these industries would have to buy all necessary allowances for imposed reductions. In the electricity sector there exist several options to reduce emissions, at least in the long run: the most important alternatives are fuel switching and investments for improved efficiency – be it on the supply or (less likely) the demand side. Finally, the demand side in the electricity market is rather inelastic and therefore electricity companies have the possibility to hand over costs of allowances to end consumers of electricity and to increase their producer surplus. This minimizes the political opposition in regard of environmental pressure and reduces dead weight losses induced by the ETS. Because of the above mentioned reasons most of the reduction obligations were and probably will be imposed onto the electricity industry (cf. Ellerman and Buchner 2006). During the first trading phase, the needs of the electricity industry determined the permit price developments (Convery and Redmond 2007). Hence, it seems worthwhile to investigate the potential impact of design issues of the emission trading scheme onto the electricity market.

Besides environmental objectives often also other goals are invoked when designing a NAP. Given that electricity is an essential commodity for an economy, aspects of security of supply and of electricity generation costs are considered. In this perspective, often arguments are put forward that an at least partial use of domestic fuels for electricity generation is preferable, because this reduces the dependence on imports. Unfortunately, the European Union relies heavily on the imports of hard coal and natural gas from third countries. Gas reserves are in the hand of few suppliers in mostly unstable regions, e.g. Russia and therefore might be insecure. Hard coal is less problematic, because it is easier and cheaper to transport and can be imported from more reliable regions. However, natural gas is preferable in environmental terms given its lower specific CO_2 emissions and therefore a policy which relies solely on emission reduction targets might lead to a situation where the vulnerability of an economy is increased. At the same time, gas is currently more expensive than coal so that base electricity prices might rise significantly. Consequently, tradeoffs in policy goals with respect to the design of a NAP occur, which are closely interlinked and difficult to assess on a qualitative basis. Obviously a policy which favours hard coal or lignite prima facie decreases fuel costs and therefore electricity prices, but at the same time increases CO_2 abatement costs which in turn have an impact on electricity prices. In order to cope with these effects, an integrated modelling of electricity and CO_2 markets is needed. In the following, a MCP model with endogenous CO_2 price calculation will be developed to analyse the effect of different permit allocation policies onto the generation costs, CO_2 permit prices and the security of supply. Thereby particular emphasis is put on modelling the non-storability of electricity and the resulting peak-load pricing behaviour. But before describing the applied model, possible allocation rules for CO_2 permits are discussed briefly.

2 CO_2 Permit Allocation mechanisms

After the expiration of the so far existing rules for NAPs in 2012, the European Union is free to choose any kind of allocation policy. One possible solution is to auction all certificates (cf. EU 2008). This has the advantage that new and old installations have to face the same permit prices. Therewith, abatement efforts before the tightening of environmental regulation (early action) and the treatment of newcomers can be considered properly (cf. Rogge et al. 2006). Theoretically, this will also lead to a first best market outcome in regard of efficiency and will avoid competitive distortions (e.g. Diekmann and Schleich 2006). Additionally, the receipts can be used by the government, who can invest into further climate protection measures and research or may lower distorting taxes and thus increase overall welfare. Herewith possibly even a "double dividend" might be obtained (e.g. Crampton and Kerr 2002).

Nevertheless, this approach strongly biases the power plant portfolio in favour of technologies with less or no CO_2-emissions and may have a significant influence onto the security of supply and the electricity price level. One disadvantage is that political pressure from some electricity companies might be increased, because they have incentives to defend revenues from sunken investments.

Because of this, one could argue that it might be better to use free allocation schemes in the future, too. If properly designed, those provide incentives to modernize the power plant portfolio, because an increase in generation efficiency saves permits which don't have to be bought or, in the case of excess supply, might be sold at the market price level of permits.

In general, the distribution of free permits has an impact onto the investment decisions of electricity producers, because it takes the effect of a subsidy for installed technologies, which may attenuate the twists introduced by a full auction of permits. This is a deliberate effect of the free allocation which is of great importance. It however strongly depends on the way free allocation is done. Hence, it is crucial to look explicitly at the effects of different allocation schemes, which were applied and discussed so far. One key issue is whether allocation will be based on emissions or on an output level of the covered firms (Böhringer and Lange 2005). But also combinations are possible as will be discussed below.

The first and so far mostly used possibility is to use a lump sum grandfathering scheme which is based on the historical emissions of one or several years of a certain installation. Some authors state that this Grandfathering scheme has the potentially best outcome in terms of efficiency (Schwarz 2006). The difference is only with regard to distributional effects and not efficiency issues. Inside such a system it is difficult to address newcomers, because they are not considered and they would have to buy permits on the market, whilst the incumbents have received them for free (Bode et al. 2006). Also early action which has taken place before the base period is not considered. During the first two trading periods different exceptions and special rules were formulated in order to address these problems. For example, in some countries also newcomers received free allowances from a special reserve which was based on technology specific benchmarks. These kinds of rules significantly increased the complexity and curtailed the practicability of the ETS during the first trading period (cf. Betz et al. 2004).

In fact the second basic alternative within (partially) free allocation is to use benchmark-based allocation mechanisms. Those provide the clear advantage that they treat existing and new installations equally, providing thus incentives for efficiency increases through replacement investment. Also early action is dealt with adequately within fully benchmark-based rules, since early movers (like later investors) benefit from the competitive advantage of lower specific CO_2 emissions. In fact, allocation to new plants is already today done mostly based on benchmarks. Since our focus is on investment incentives, we focus in the following on these benchmark-based allocation rules.

The key question then is, whether the benchmarks are differentiated according to fuels and/or technology used. A first advantage of doing so is that investment incentives may be shifted to domestic and less vulnerable fuels. Another advantage is that overallocation can be avoided. Otherwise low carbon installations might finance themselves only out of the proceeds of selling excess certificates. Yet one should expect that every allocation, which is based on more specific characteristics of power plants reduces the incentives for fuel switching and increases CO_2 abatement cost (e.g. Neuhoff 2006).

If nevertheless specific allocation rules are searched for, different possibilities may be considered: Firstly, the fuel-specific carbon content may be taken into account when fixing the benchmark. Moreover the different operation times of power plant types may be considered, which are a result of different proportions of fixed and variable costs. Gas fuelled power plants have usually to face less capital costs and higher fuel prices, therefore they are traditionally planned for operation only during periods of high load. Contrarily, coal fired plants are operated at longer periods, because this lowers their average costs of electricity generation Using an average of full load hours twists investments in favour of gas fuelled plants, because they will get more certificates then with an allocation based on expected operation hours. The higher amount of free certificates provides incentives for investments into gas- and carbon free technologies. If this is not desired, a fuel and operation time specific benchmark may be used.

For the subsequent quantitative analysis of these potential allocation principles, the typical cases summarized in Table 1 will be considered:

Table 1: scenarios of different allocation policies.

Scenario name	Allocation policy	Considered Specifications (for new plants)
0	No emission cap	-
A	Auctioning	-
B	Benchmark based on specific plant needs	Specific fuel benchmarks Specific operation time
S	Standard benchmark	standard fuel benchmark standard operation time
D	Fuel specific benchmark	Specific fuel benchmark Standard operation time

The scenario 0 assumes that there would be no emission cap after the expiration of the Kyoto-protocol. The scenario A assumes full auctioning and the scenario S a standard benchmark scheme which is applied for all generation technologies. Within the scope of this article the scenarios B and D are of particular interest, because they presume a specific permit allocation based on fuel specifics (D) or on fuel and operation time specifics (B). In all scenarios it is assumed that all countries within the EU-27 apply the same allocation principles. In the following the impact of these different allocation policies will be analysed with the use of a peak load pricing model which is implemented as a MCP model. In order to address the interplay between investment decisions, CO_2- and electricity prices, endogenous decisions regarding investment into generation capacities and CO_2 abatement are modelled. As we assume perfect competition in the electricity market, the optimal generation portfolios resulting from the presumed scenarios can be derived.

3 Quantifying the impact of allocation rules

So far there have been several analyses which tried to quantify the effect of different permit allocation rules. Most of these approaches used a linear (Neuhoff et al. 2006; Bartels and Müsgens 2006) or a mixed integer programming model (Schwarz 2007) with exogenously given CO_2 prices. We implement our analysis in the form of a MCP model, in order to model explicitly the interdependency between investment decisions, operational decisions within different load segments, allocation rules and CO_2 abatement prices. The level of technical detail achievable with this approach is certainly lower than with conventional LP or even MIP models, yet the focus of the subsequent analysis is anyhow on general insights. Thereby however the specific challenges of the electricity market (non-storability) and of the allocation rules (impact on investments) have to be handled adequately. In order to do so a static equilibrium is modelled covering one year of operation but with endogenous investment, along the lines of the Peak-Load-Pricing model, first developed by Boiteux (1960). This model is then extended to include CO_2-certificates, their endogenous price formation and the impact of allocation rules on investments.

One of the key concepts of the model is that demand has to be met within every load segment and that a cost minimal capacity for the serving of any load segment is given. Due to the fact that the exogenously given capacity is not sufficient to cover all load segments, new capacities have to be build. Herewith, the decision to invest whether into new gas or coal power plants and additionally exchange old capacities with more efficient ones is heavily influenced by the allocation rules for CO_2 permits.

The model is implemented as a MCP model because it can incorporate dual and primal restrictions. In the following the complementary slackness conditions, which characterize the economic equilibrium of the model, are depicted.

First of all the excess demand condition of the model is described by (1), whereby $Q_{i,s}$ describes quantities supplied by i different technologies for every load segment s. P_s^{Elec} stands for the price of electricity and L_s for the served load in the segment s. The scalar a depicts the slope of the (slightly) elastic demand function;

$$\sum_i Q_{i,s} \geq L_s(1-a(P_s-\bar{P})) \qquad \perp \qquad P_s^{Elec} \geq 0 \qquad \forall s \tag{1}$$

The complimentary slackness conditions states that excess supply can only occur when electricity prices are zero, i.e. no scarcity occurs.

The supply side can be described in a first step by the need for sufficient generation capacities:

$$Cap_i^{total} * avail_i - Q_{i,s} \geq 0 \qquad \perp \qquad \Pi_{i,s}^0 \geq 0 \qquad \forall s, \forall i \tag{2}$$

Thereby Cap_i^{total} stands for the capacity and $avail_i$ for the availability of technology i. This condition is complimentary to positive raw operating profits $\Pi_{i,s}^0$, hence an operating profit is only possible in time segment where a technology is used up to its capacity limit.

Nevertheless no technology will produce under market conditions, if cost recovery is not ensured. This is described by the next condition:

$$C_i^{misc,\mathrm{var}} + \sum_{f \in F^i} \frac{1}{\eta_i}(E_f P^{CO_2} + C_f) + \Pi_{i,s}^0 \geq P_s \qquad \perp \qquad Q_{i,s} \geq 0 \qquad \forall s, \forall i \qquad (3)$$

Thereby, the sum of miscellaneous variable costs $C_i^{misc,\mathrm{var}}$, the costs P^{CO_2} for fuel-specific CO_2 emissions E_f and fuel costs C_f plus the raw operating profit $\Pi_{i,s}^0$ may only exceed the current price, if production is zero.

The following Karush-Kuhn-Tucker conditions describe the economic logic underlying the continued use of capacities in the presence of a fixed cost component. The fixed costs C_i^{fix} have to be recovered for every unit of usable generation capacity. Thereby also the possibility of receiving free certificates for available capacity has to be taken into account:

$$C_i^{fix} + \Pi_{i,s}^1 \geq \sum_s \Pi_{i,s}^0 dur_s + I(scenario) * (Fullh_i * co2\_bench_i * P^{CO_2}) \quad \perp \quad Cap_i^{total} \geq 0 \quad \forall i \qquad (4)$$

Those certificates are based on (expected) full load hours $Fullh_i$ and a benchmark $co2\_bench_i$ which may depend on the CO_2 content of the fuel. I is an index function which states that revenues from free certificates only occur in some scenarios.

This condition is complemented by another one, describing the relationship between total capacities, new investments Cap_i^{new} and existing capacities Cap_i^{old}. Total capacities are equal to the sum of the latter two except for the case where the operating profit $\Pi_{i,s}^1$ after fix costs is zero:

$$Cap_i^{new} + Cap_i^{old} - Cap_i^{total} \geq 0 \qquad \perp \qquad \Pi_{i,s}^1 \geq 0 \qquad \forall i \qquad (5)$$

Then the model may discard some of the existing capacity given that it provides no operating margin.

Investment on the other side implies that the operating profit after fix costs covers the cost of investment. The Investment costs C_i^{Invest} of technologies, available for investment $i \in I^{Invest}$ multiplied with the annuity factor af_i have to be equal to the operating profit in case of strictly positive new capacities:

$$C_i^{Invest} * af_i + I(scenario) * (Fullh_i * co2\_bench_i * co2\_alloc\_val) \geq \Pi_{i,s}^1$$
$$\perp \qquad Cap_i^{new} \geq 0 \qquad \forall i \in I^{Invest} \qquad (6)$$

In the case of free allocation, the investment costs may be increased by a shadow value of freely allocated permits *co2_alloc_val*. This is because free allocation might incentivise investment to a point, where the number of certificates allocated to plants exceeds the overall CO_2 emission limit. What would happen in reality in such a case is unclear – in the model world the assumption is that the emission limit will be enforced and that this provides some extra value to those who obtained some of the rare certificates which is precisely this CO2 allocation value.

Equation (6) together with the previous profit conditions (4) and (3) provides the zero-profit condition familiar to those who do macro-economic equilibrium modelling. The assumptions here are those of a perfect competition world and consequently the profits which can be obtained by a technology are limited to annualized investment costs, which is the standard outcome also of every peak load pricing model. Only in the case of free permit allocation extra margins might be obtained - these can be interpreted as a governmental subsidy.

In order to complete the model, a CO_2 bound has to be introduced. Given the model aim, the CO_2 bound is set exogenously, but CO_2 prices are an endogenous model result. For reasons of simplicity we do neither consider abatement opportunities of the other sectors within the ETS, nor opportunities to use reduction potentials from the clean development mechanism or joint implementation projects.

$$co2\_bound \geq \sum_i \sum_s (\sum_{f \in F^i} \frac{1}{\eta_i} E_f) Q_{i,s} d(s) \qquad \perp \qquad P^{CO_2} \geq 0 \qquad \forall s, \forall i \qquad (8)$$

As already mentioned above, the allocation of permits has to be considered too in order to avoid excess certificate allocation. This leads to an additional condition on the CO_2 bound:

$$co2\_bound \geq \sum_i (Fullh_i * co2\_bench_i * Cap_i^{total}) \quad \perp \qquad co2\_alloc\_val \geq 0 \qquad (9)$$

If this condition is binding, the certificates allocated for free may get a positive value and thus provide some extra rent to the power plant owners.

4 Application

The model is applied to the year 2015 which is situated after the Kyoto obligation period. We consider the entire electricity sector of the EU-27 countries without any differentiation between countries or regions, since at the current stage of Post-Kyoto negotiations it is most likely that emissions trading will at least be continued within this region. The used data is calibrated to a recent DG-TREN study (EC 2005) which depicts future trends in European electricity markets. The model uses an aggregated stylized load duration curve; given that data availability at a European scale for load data still is limited. The load is divided into 876 load segments of 10 hours each (cf. Figure 1).

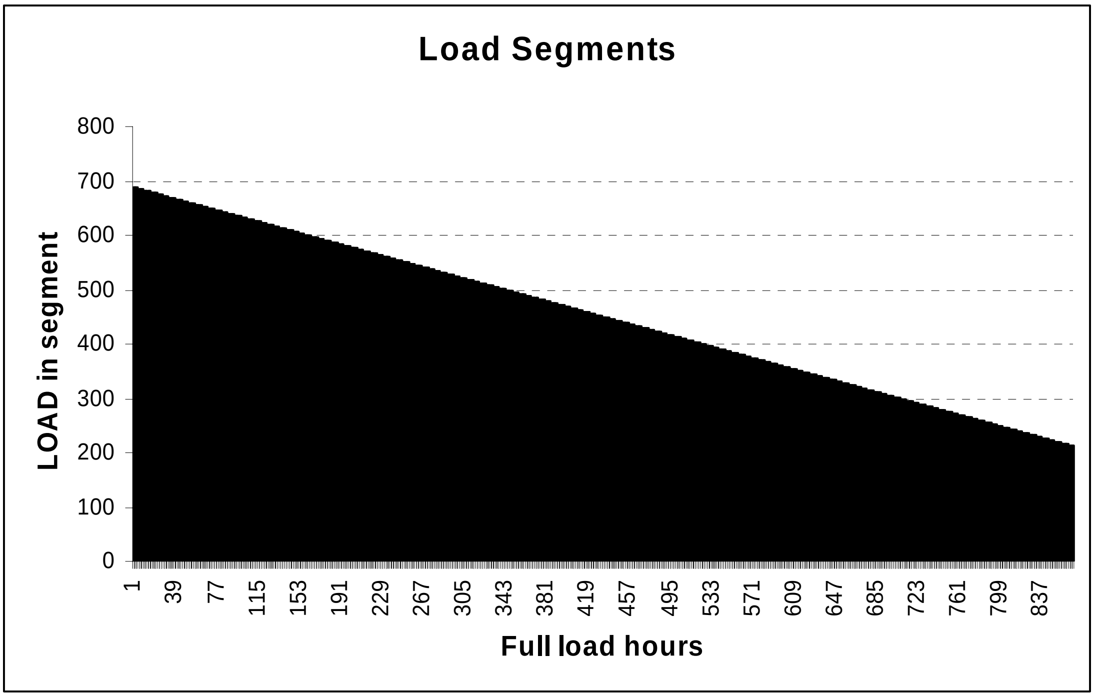


Figure 1: Load segments within the model

Generation technologies are divided into seven technology classes i, of which only two are available for investment i^{Invest}. We assume that only decisions on new coal and gas power plants are dependent on market prices. Capacities of the other technologies are set exogenously, because their development relies heavily on political decisions of phase out (Nuclear) or promotion (Wind and other Renewables), which can not be considered within the model. We focus on new gas and coal fired power plants as key technologies in the year 2015 playing an important role in the determination of optimal abatement (Delarue and D'haeseleer 2006). The key characteristics of the technology classes considered are summarized in table 2:

Table 2: Key technology specifications.

Technology	**Efficiency**	**Capacity in 2015 [GW]**	**availability**	**Investment cost [€/MW]**
Coal old	0.36	155	0.85	-
Gas old	0.46	73	0.85	-
Nuclear	0.35	129	0.85	-
Hydro& Wind	0.8	221	0.33	-
Gas CHP	0.4	109	0.57	-
Coal new	0.46	Endogenous investment	0.85	1000
Gas new	0.58	Endogenous investment	0.85	500

Fuel prices are assumed to amount up to 20 €/MWh for natural gas used in power plants and due to a heat bonus only 9 €/MWh for CHP plants. The coal price takes the value of 7.8 €/MWh and the fuel cycle cost of nuclear plants are set at 2 €/MWh$_{th}$. The emission cap within the EU power production sector is set at a level of 1261 Million tons of CO_2 per year, corresponding to a reduction by 15 % compared to 1990 levels. Within the model calculations for the demand function a slope of -0.001 is assumed, with a price level of $\bar{P}$ for reference demand of 33 €/MWh. Hence demand price elasticity is about 0.03.

The allocation rules and corresponding parameters depend on the modelled scenario (cf. table 1). Within the scenarios, the values for $Fullh_i$ and $co2\_bench_i$ vary.

Scenario name	**Parameter *I(scenario)***	**Fuel specific emissions per output unit for permit allocation [t/MWh$_{el}$]**	**Operation time for permit allocation**
0	0	-	-
A	0	-	-
B	1	Coal 0.696 Gas 0.345	New coal 7000 New gas 6000
S	1	All 0.345	All new plants 6000
D	1	Coal 0.696 Gas 0.345	New coal 6000 New gas 6000

5 Results

Without any limitations, the CO_2 emissions of the optimal portfolio in scenario 0 amount up to 1621 Million tons of CO_2; this implies an increase in emissions of approximately 9.3 % compared to 1990 levels. In all other scenarios the emission target will be met, but the costs and optimal portfolios depend on the allocation of permits. Figure 2 represents the total capacities within the analysed scenarios.

As a result, it can be seen that the overall generation capacity is rather similar in all scenarios – not surprisingly, given that peak load is similar across all scenarios. The lowest overall capacity is observed in the auctioning scenario A, given that prices are rather high there and no incentives exist to maintain old plants online. That prices do not exert a strong impact on total capacity is illustrated by the fact that the scenario 0 without emission trading and with correspondingly low prices has a total capacity which is only slightly higher. Yet obviously the introduction of the ETS has a considerable impact on the structure of the generation park.

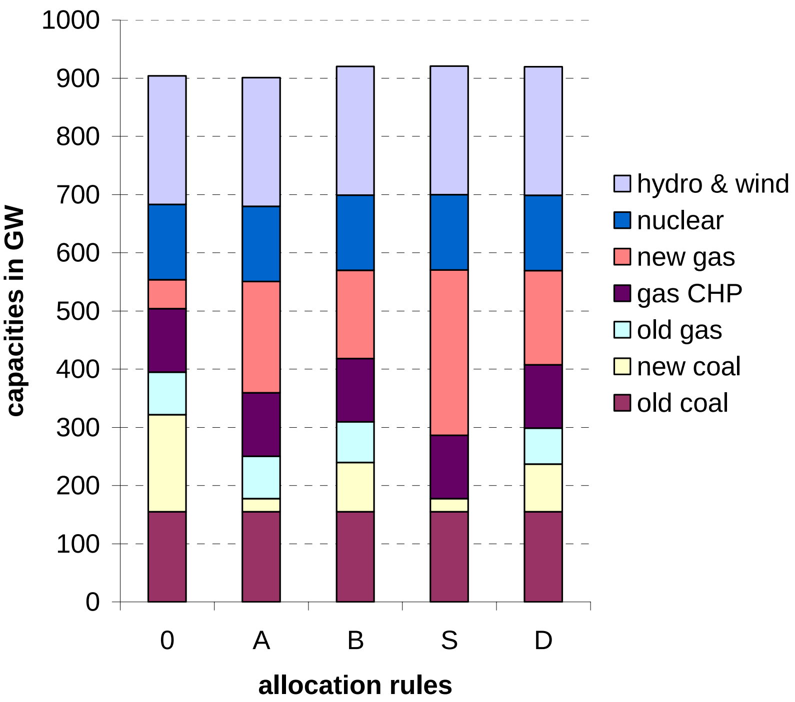


Figure 2: Resulting generation capacities in the different scenarios

Without emission trading investments occur predominantly in new coal plants, whereas with auctioning mostly new gas plants are built. The use of a standard benchmarking-based allocation (scenario S) increases even more the construction of new gas plants, which then mostly replace old gas plants. Apparently the certificates allocated make such new investment more valuable than maintaining old plants in activity. When a fuel specific benchmark (D), or even additionally technology specific full load hours are considered (B), the overall generation capacity increases slightly. But more importantly, these allocation rules also affect heavily the relation between new gas and coal fired plants. With specific benchmarks, the focus of investments is shifted from gas to coal fired power plants. This result is an explicit goal of this allocation policy and therefore comes at no surprise. Yet the amount of investment in new coal plants is considerably lower than in the non-emission constrained case. This result is underpinned by the results on electricity generation. Here the shift from gas to coal under specific allocation rules is even less pronounced. In all emission-constrained cases, coal based generation remains below 1000 TWh, whereas in the unconstrained case almost 2000 TWh stem from coal. By contrast the share of gas in production is always between 1250 TWh and 1450 TWh if the emission constraint is imposed.

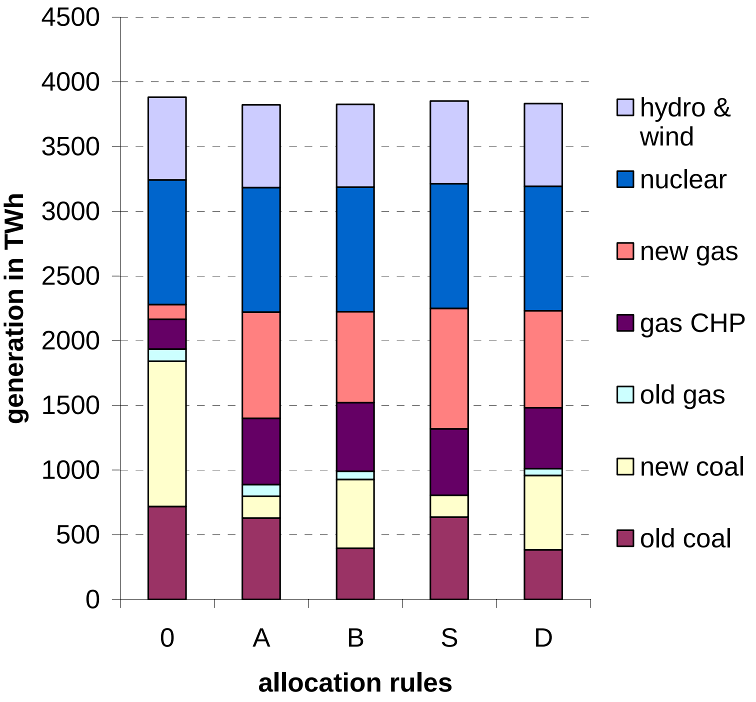


Figure 3: Resulting electricity generation in the different scenarios

Hence obviously the usage of gas fired plants is not heavily influenced. Thus, the objective of limiting the dependency on foreign gas supply is only attained to a rather limited extent and this improvement has to be weighted with the effect of specific benchmarking on CO_2 and electricity prices. The major reason for the results obtained is that the emission cap has to be fulfilled, and this is not possible if future generation relies to heavily on coal – independently of the political support for this generation technology. The specific benchmarking mostly leads to a substitution of the use of older coal plants towards new coal plants, which then also allows for some replacement of gas-fired generation compared to the auctioning case.

The market prices obtained differ significantly between the analysed scenarios, as can be seen from Figure 4. Whilst in the case of auctioning the CO_2-price is about 23 €/MWh, it increases when specific benchmarking rules are applied. The more technology specific the benchmark for the allocation rules, the higher the emission prices get.

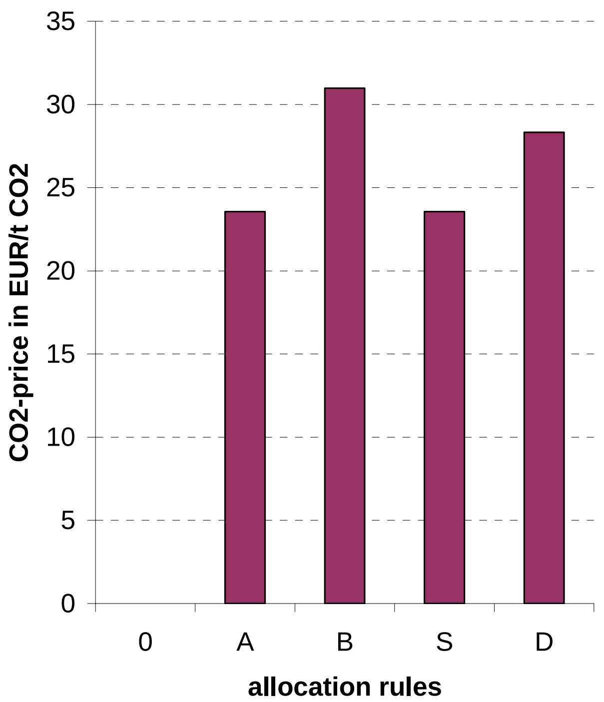
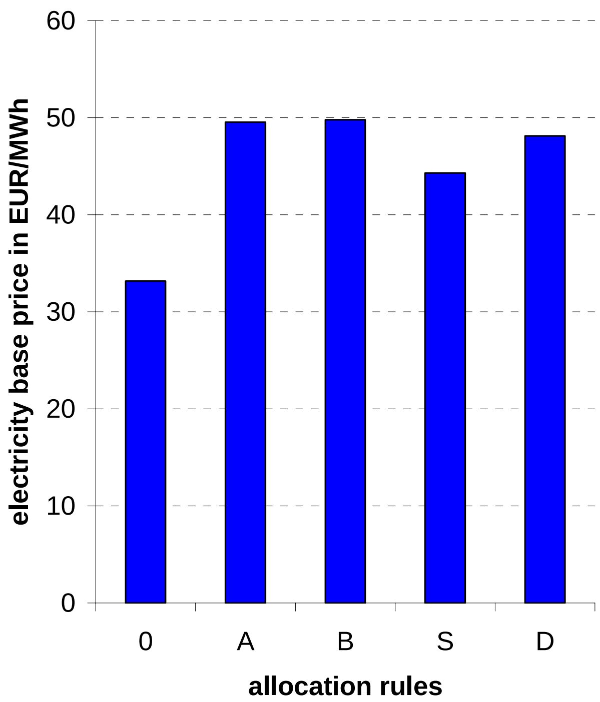


Figure 4: *Equilibrium CO_2-price in the different scenarios*

This result is a straightforward consequence of changing the relative prices of different CO_2 mitigation options. Whilst in the auctioning case, fuel switching from hard coal towards natural gas is the cheapest possibility for a larger share of load segments, the introduction of specific benchmarking lowers the costs of coal investments and thus distorts prices towards coal-based generation. In order to achieve nevertheless the CO_2 reduction target, higher CO_2 prices are needed, which then increase the attractiveness of replacement investments.

Owing to the fact that power plant operators reflect the (opportunity-)costs of CO_2 certificates within their power plant dispatch, the increase in permit prices will induce increases in average electricity costs. Without consideration of ramp rates and start up costs a power plant is always run if the market price is higher than the costs of fuel, CO_2 and other variable costs (cf. condition (2)). The CO_2-induced cost increases are compensated partly or even overcompensated by decreased average fuel cost and fuel consumption, if an intensified use of modern and efficient coal plants occurs. This is, because more load segments are served by coal and not gas powered plants and fuel input is reduced compared to old coal plants. Figure 5 summarizes the overall effects onto electricity prices within the analysed scenarios. Here, it can be seen that in all ETS-scenarios the prices are close to each other at just below 50 €/MWh. Only in the reference scenario without any CAP and trade system the electricity price is much lower at about 33 €/MWh. This is a consequence of the relatively high share of coal fired power plants within the power plant portfolio and the absence of emission prices which are consequently not reflected within the base price. The price in the scenario B, where a technology specific benchmarks regarding full load hours and fuel is applied, is even the highest. Only in the scenario S with standard benchmarks used for allocation, a price decrease by about 10 % compared to the reference case is obtained.

Graphic 5: scenario results: base electricity prices.



Hence, the strategy of improving the competitiveness of coal fired plants in order to achieve lower electricity prices provides no substantial effects. The impact of reduced fuel costs and lower permit purchase needs is more than outweighed by increased permit prices. This is a surprising result; because one of the potential advantages of limiting the ETS induced bias towards gas fuelled power plants, through fuel specific benchmarks, is not confirmed. Yet one has to be aware, that this result has been derived under the assumption that no CDM or JI credits can be bought and that the other ETS sectors can not contribute significantly to the target emissions' reduction. If these assumptions are weakened, the results may differ and an allocation based on specific benchmarks might indeed contribute to lowering the electricity price level.

6 Conclusions

Our analysis used a simplified static peak load pricing model with endogenous calculation of CO_2 abatement and investment into electricity generation capacities. Thereby, the quantitatively most promising medium term options for CO_2 abatement were considered: switching of fuels and investments into efficiency at the demand and the supply side of the electricity sector. We analysed the impact of different permit allocation rules onto optimal power plant portfolios under perfect competition. Our main interest was to investigate the impact of different allocation schemes. Those are often designed to weaken the bias towards less carbon intensive fuels and to support investment into modern coal-fired power plants and are also expected to contribute to lower electricity prices and security of supply. We focused our analysis onto these two aspects, because often they are used to legitimize the application of specific benchmarking measures. Not very surprisingly, we identified higher CO_2 prices under these regimes given they distort the efficiency of the emission trading scheme. Yet additionally our findings indicate that, due to increased CO_2–permit prices, there is no positive effect on electricity prices. The effect on natural gas import dependency is also limited. The reason for this is the CO_2 emission cap. If promoted by specific benchmarks, new coal power plants are mostly crowding out the use of old coal fired plants within an optimal power plant portfolio. This decreases the coal consumption, but only has a limited effect onto gas consumption. In comparison to the auction scenario, the benchmarking scenarios faintly hinder the dispersion of gas plants into the medium load segments.

The results of our analysis stress that the application of technology specific benchmarking rules lead to consequences not in line with the original policy goals. For this reason it is advisable not to apply any specific benchmarks and to focus onto the possibility to allocate all permits freely through the use of standard benchmarks or an auction within the post Kyoto trading period.

Literature

Bartels, C.; Müsgens, F. (2006): Do technology specific CO_2-allocations distort investments? IAEE (ed.),Proceedings of the 29th IAEE International Conference. 7-10 June 2006 in Potsdam/Germany.

Betz, R., Eichhammer, W., Schleich, J. (2004): "Designing National Allocation Plans for EU Emissions Trading – A First Analysis of the Outcomes", Energy & Environment, 15(3), 375-425.

Bode, S.; Hübl, L.; Schaffner, J.; Twelemann, S. (2006): Discrimination against Newcomers: Impacts of the German Emission Trading Regime on the Electricity Sector, HWWA Discussion paper No. 316; available under: http://www.wiwi.uni-hannover.de/Forschung/Diskussionspapiere/dp-316.pdf.

Böhringer, C.; Lange, A. (2005): On the design of optimal grandfathering schemes for emission allowances, European Economic Review, Volume 49, Issue 8, pp. 2041-2055.

Boiteaux, M. (1960): Peak Load Pricing, Journal of Business, Vol. 33, pp. 157-179.

Crampton, P.; Kerr, S. (2002): Tradable Carbon Permit Auctions: How and Why to Auction Not Grandfather; Energy Policy, Vol. 30, pp. 333-345.

Coase, R. (1960): The Problem of Social Cost, The Journal of Law& Economics Vol. III, S.1-44, 1960.

Convery, F.J.; Redmond, L. (2007): Market and Price Developments in the European Union Emissions Trading Scheme, Review of Environmental Economics and Policy, Vol.1 No.1.

Delarue, D.; D'haeseleer, W.D. (2006): Price determination of ETS allowances through the switching level of coal and gas in the power sector, International Journal of Energy Research, Volume 31(11), Pages 1001 – 1015.

Diekmann, J.; Schleich, J. (2006): Auktionierung von Emissionsrechten. Eine Chance für mehr Gerechtigkeit und Effizienz im Emissionshandel, Zeitschrift für Energiewirtschaft, Vol. 30(4), pp. 259-266.

European Comission (1999): Preparing for Implementation of the Kyoto Protocol, COM(1999)230.

European Comission (2003): establishing a scheme for greenhouse gas emission allowance trading within the Community and amending Council Directive 96/61/EC, COM(2003)87.

European Commission (2005): European Energy and Transport: Trends to 2030- Update 2005, available under: http://ec.europa.eu/dgs/energy_transport/figures/trends_2030_update_ 2005/energy_transport_trends_2030_update_2005_en.pdf.

European Environmental Agency (2007): Europe's environment – the fourth assessment, available under http://reports.eea.europa.eu/state_of_environment_report_2007_1/en

European Union (2008): Boosting growth and jobs by meeting our climate change commitments Reference IP/08/80, available under http://europa.eu/rapid/pressReleases

Ellerman, D.; Buchner, B. (2006): Over-allocation or abatement? A preliminary analysis of the EU ETS based on the 2005 emissions data, available under: http://web.mit.edu/ceepr/www/2006-016.pdf.

Harrison, D.; Radov B. D., (2002): Evaluation of Alternative Initial Allocation Mechanisms in a European Union Greenhouse Gas Emissions Allowance Trading Scheme, nera consulting economists.

International panel on climate change (2007): Fourth assessment report 2007; available under: http://ipcc-wg1.ucar.edu/wg1/wg1-report.html.

Neuhoff, K.; Keats, K.; Sato, M. (2006): Allocation, Incentives and Distortions: The Impact of EU ETS Emissions Allowance Allocations to the Electricity Sector, Cambridge working paper in economics, No. 0642.

Nordhaus, W.D.(2007): The Challenge of Global Warming: Economic Models and Environmental Policy, available under: http://www.econ.yale.edu/~nordhaus/DICEGAMS/dice_mss_060707_pub.pdf

Rogge, K.; Schleich, J.; Betz, R. (2006): EU emissions trading: an early analysis of national allocation plans for 2008–2012, Climate Policy forthcoming, pp. 361–394.

Schwarz, H.G. (2007): The European emission trading system and the present draft of the German national allocation law: A critical evaluation of the effects on electricity production and investment patterns, Working Paper University of Erlangen.

Tietenberg, T. H. (1986): Emissions Trading, an exercise in reforming pollution policy, Resources for the future, Washington D.C., 1985.